LRMC of Regulated Tariffs – Updated final report

A REPORT PREPARED FOR THE ECONOMIC REGULATION AUTHORITY

June 2012

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1 Introduction

The Economic Regulation Authority (Authority) commenced on 11 July 2011 an inquiry into the efficiency of Synergy's costs and tariffs (Synergy Review). The Synergy Review was referred to the Authority under section 32(1) of the *Economic Regulation Authority Act 2003*, which provides for the Treasurer to refer to the Authority inquiries on matters relating to regulated industries.

1.1 ERA terms of reference

In accordance with the Treasurer's Terms of Reference, the Authority's task for the Synergy Review is to:

1. consider and develop findings on the:
    a. efficiency of Synergy's operating and capital expenditure;
    b. efficiency of Synergy's procurement of wholesale electricity; and
    c. efficiency of Synergy's procurement of Renewable Energy Certificates.
2. determine the efficient cost-reflective level for each tariff under the By-Laws over the period 2012/13 to 2015/16, including:
    a. developing recommendations regarding the number of regulated electricity tariffs, and whether any tariffs should be amalgamated; and
    b. taking into account the competitive markets within which Synergy operates and the current operating subsidy arrangements when considering the cost-reflective level of each tariff;
3. develop a methodology to regularly re-determine the efficient cost-reflective level for each tariff and recommend a period for the review of the efficient cost-reflective level of tariffs;
4. consider whether regulated tariffs for contestable large business customers should be phased out, with reference to the competitive nature of this segment of the electricity market; and
5. if regulated, large contestable tariffs are to be phased out, provide recommendations on which tariffs should be phased out and over what timeframe.

1.2 Frontier Economics' engagement

Frontier Economics has been engaged by the Authority to provide advice on the Authority's second task: to determine the efficient cost-reflective level for each tariff under the By-Laws over the period 2012/13 to 2015/16. Specifically, we

have been engaged by the Authority to estimate the long run marginal cost (LRMC) of supplying energy to the meet the load shape of regulated customers in each tariff class. The LRMC of supplying energy to regulated customers is a widely used method of estimating the wholesale energy cost component of regulated tariffs.

We have also been engaged by the Authority to provide advice on the efficient level of retail operating costs in Western Australia over the period 2012/13 to 2015/16 and to provide advice on the efficiency of Synergy's procurement of wholesale electricity. Our advice on these matters is set out in separate reports to the Authority.

1.3 This updated final report

This updated final report sets out Frontier Economics' advice to the Authority on the cost-reflective tariffs that a retailer in Western Australia would incur in retailing to customers on regulated tariffs over the period from 2012/13 to 2015/16.

In March 2012 Frontier Economics provided an earlier version of this report to the Authority.[1] The earlier version of the report was used by the Authority to inform its analysis for the Authority's Draft Report for the Synergy Review.[2]

1.3.1 What has changed in this updated final report?

This report updates Frontier Economics previous advice to the Authority. Having considered stakeholders' submissions to the Authority's Draft Report a number of key input assumptions have been updated:

- The weighted average cost of capital (WACC) has been updated from 7.8 per cent to 6.66 per cent.
- The capital cost of OCGT plant and CCGT plant have been increased, with the capital cost of OCGT plant now reflecting the cost estimate from the IMO's most recent calculation of the Maximum Reserve Capacity Price.
- The coal price for generators has been increased from $2.21/GJ to $3.25/GJ to reflect the Authority's view on the likely net-back price of coal in Western Australia.

1 Frontier Economics, *LRMC of Regulated Tariffs – Final report*, A report prepared for the Economic Regulation Authority, March 2012 (**Frontier March 2012 Report**).

2 Economic Regulation Authority, *Inquiry into the Efficiency of Synergy's Costs and Electricity Tariffs*, Draft Report, April 2012.

- The gas cost for generators has been increased by $1.00/GJ to reflect the Authority's view on the likely response to an increase in the coal price to the net-back price of coal.

These updated input assumptions have resulted in us updating our estimates of the LRMC of supplying energy to the meet the load shape of regulated customers in each tariff class.

1.3.2 Structure of this report

Frontier Economics has previously provided to the Authority

This report is structured as follows:

- Section 2 provides an overview of our approach to estimating efficient costs
- Section 3 sets out the input assumptions used in our analysis
- Section 4 details the results of our analysis
- Section 5 discusses the impact of the carbon price
- Section 6 summarises our advice to the Authority.

Appendix A provides detailed results.

2 Overview of modelling approach

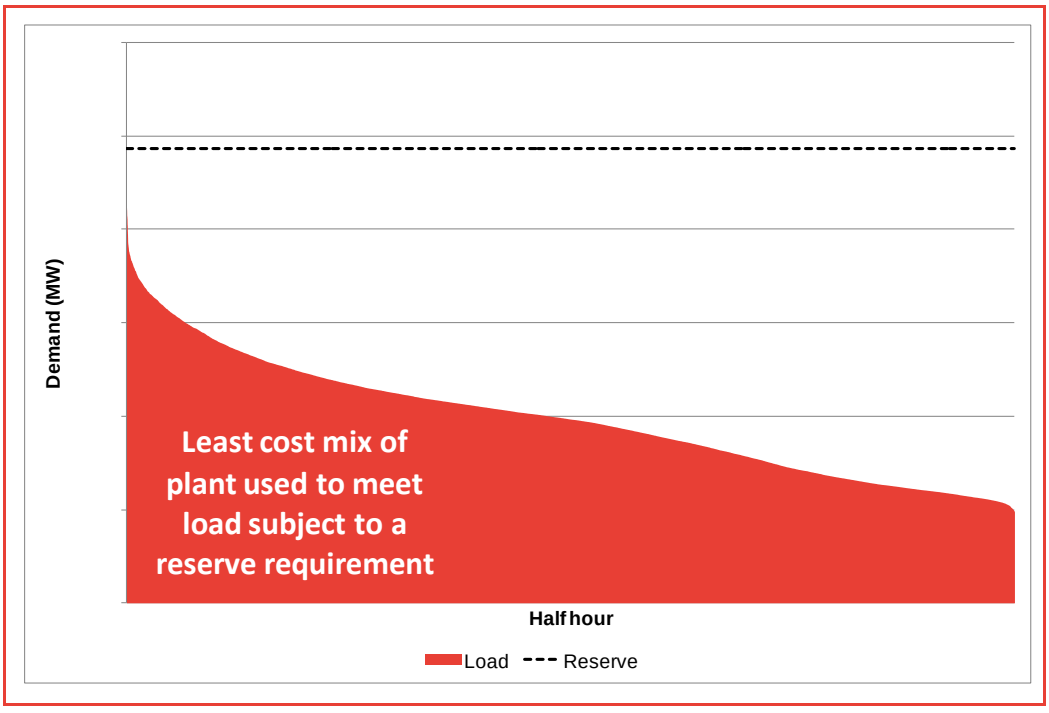
Frontier Economics has been engaged to determine the LRMC of energy to supply regulated customers, as an indicator of the efficient wholesale energy cost for regulated customers.

The LRMC of energy is typically determined on the basis of the least cost mix of plant required to meet load to a particular security standard. LRMC can be calculated in a number of different ways. In determining the LRMC for each tariff class, we have adopted a stand-alone LRMC approach. This involves:

- modelling the load shape for each tariff class (as opposed to system load)
- assuming no existing generation (as opposed to assuming the current mix of existing generation)
- determining the least cost mix of new generation options to meet demand subject to a reserve requirement.

This approach is illustrated in Figure 1. The stand-alone LRMC approach is also referred to as a 'Greenfield' approach. The alternative approach of modelling the full system (the SWIS) and all existing generation is often referred to as a 'Brownfield' LRMC.

Figure 1: Illustration of approach



Source: Frontier Economics

We have adopted a stand-alone LRMC approach in order to estimate costs for each tariff class *individually*. Using this approach measures the cost associated with each tariff class load shape, which may be peakier or flatter than system load as a whole.

2.1 Important caveats to the stand-alone LRMC approach

There are some important caveats to the stand-alone LRMC approach, as noted below.

2.1.1 Peakiness and overnight load shapes

Within the context of the stand-alone LRMC approach the concept of peakiness relates only to the range of demand, not the timing. For this reason a peaky load shape associated with overnight demand for electricity involves greater costs even though this load occurs during off-peak times. We are of the view that an alternative to the stand-alone LRMC should be used to set the tariffs for these overnight load classes.

2.1.2 Stand-alone LRMC versus system modelling

The stand-alone LRMC approach, as a cost benchmark for a load shape that is a subset of total load in an actual electricity system, is necessarily an abstraction. It differs from modelling that seeks to determine outcomes for a real world electricity system (such as the SWIS). As a result, a number of assumptions that are relevant to modelling a real world electricity system become redundant or inapplicable within the stand-alone LRMC approach. For example, generation unit sizes are not applicable when some load shapes only reflect total demand of less than 10 MW. Similarly, issues regarding the capacity of upstream infrastructure, such as gas pipelines, are not relevant to the operation of a theoretical, new build system for a given load shape.

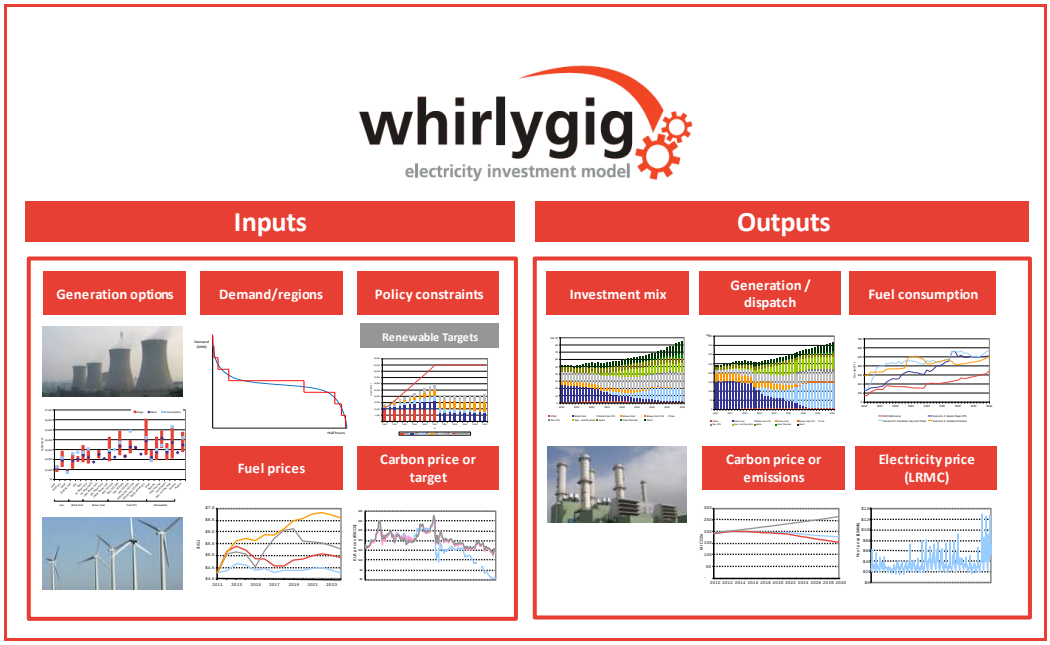
We have ensured that assumptions used in the modelling are consistent with the objective of arriving at an optimal cost benchmark for each load shape based on the costs of new entry generation plant and including a reserve margin.

2.2 Implementing the stand-alone LRMC approach

We have used our proprietary least-cost investment model for electricity markets – *WHIRLYGIG* – to determine the stand-alone LRMC for the relevant tariff classes. *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of plant options to meet demand, subject to any

regulatory or other constraints (such as a reserve requirement or carbon price). Key output variables include: least-cost investment, an estimate of LRMC of meeting load, and the cost of any plant required to meet any regulatory obligations. A summary of inputs and outputs from *WHIRLYGIG* is provided in Figure 2.

Figure 2: Model inputs and outputs



For the stand-alone LRMC, *WHIRLYGIG* has been used to model each load shape for each year *independently*. That is, for a given load shape *WHIRLYGIG* has not been used to determine an optimal investment path over the four years of the modelling period but rather an optimal investment mix for each year independently.

3 Input assumptions

The stand-alone LRMC approach requires a number of input assumptions, which are detailed in this section. Key inputs include:

- Demand for each regulated tariff class
- Reserve requirement
- Generation assumptions
- Carbon price.

Each of these assumptions is discussed in turn below.

For the purposes of the Frontier March 2012 Report we modelled three scenarios for the Authority – a Base Case, a High Case and a Low Case. The High Case and the Low Case were developed by assuming that several input parameters had values that would lead to higher and lower cost estimates.

For the purposes of this updated final report, we have modelled only a Base Case (noting that a number of the input assumptions for this Base Case have been updated since the modelling of the Base Case for the Frontier March 2012 Report). We have not modelled a High Case and a Low Case. However, we have modelled the Base Case without a carbon price. Modelling the Base Case with a carbon price and without a carbon price enables us to directly observe the impact of the introduction of a carbon price on the stand-alone LRMC.

3.1 Demand

Demand for each regulated tariff class was provided by Synergy on a forecast half hourly basis for the period 2012/13 to 2015/16.

For the purposes of the Frontier March 2012 Report, we estimated the stand-alone LRMC for each of the 13 regulated tariff classes:

- A1
- B1
- C1
- D1
- K1
- L1
- R1
- L3
- M1

- R3
- S1
- T1
- UM (modelled as a proxy for W1)

The analysis for the Frontier March 2012 Report also considered a number of additional demand profiles:

- SM1
- SL
- Synergy total load
- A1B1 = sum of the A1 and B1 load data
- Aggregate 1 = sum of the 13 regulated tariffs
- Aggregate 2 = sum of the 13 regulated tariffs plus SM1

For the purpose of this updated final report, we have been asked by the Authority only to update the estimate of the stand-alone LRMC for Synergy's total load. We have not been asked to update the estimate of the stand-alone LRMC for each of the 13 regulated tariff classes.

The demand data that we have used to estimate the stand-alone LRMC for Synergy's total load is the same demand data as was used for the Frontier March 2012 Report.

3.2 Reserve requirement

In modelling the stand-alone LRMC we have included a reserve requirement which stipulates that capacity must be at least 15 per cent greater than peak demand.

The assumption of a 15 per cent reserve margin is consistent with the previous work performed in Western Australia for the Office of Energy in 2007 and in NSW for the Independent Regulatory and Pricing Tribunal (IPART).

Reserve margins in actual electricity systems are calculated differently. For example, in the South West Interconnected System (SWIS) the Market Rules[3] state that the IMO should maintain a reserve margin equal to the greater of

- 8.2 per cent of forecast peak demand, and
- the maximum capacity of the largest generating unit.

[3] Market Rules, Section 4.5.9.

The first of these – 8.2 per cent of forecast peak demand – is currently the greater quantity.

However, the reserve margin required under the Market Rules cannot be directly translated into the stand-alone LRMC approach. The Market Rules require that the forecast peak demand should be calculated to a probability level that would not be expected to be exceeded in more than one year in 10 (which is equivalent to a 10% Probability of Exceedence (POE) forecast). The 8.2 per cent reserve margin is applied to the 10% POE forecast. The demand for the regulated tariffs that has been supplied by Synergy is not on a 10% POE basis, meaning that applying the 8.2 per cent reserve margin to the regulated demand forecasts would likely understate the reserve margin required.

We have adopted a reserve margin of 15 per cent because we consider it is appropriate to the stand-alone LRMC approach in order to achieve objectives similar to what market operators seek to achieve in actual electricity markets.

3.3 Generation assumptions

WACC

We have assumed a pre-tax, real discount rate of 6.66 per cent. This is based on the Authority's decision on the appropriate discount rate for the purposes of electricity generation assets.

Capital costs

Capital costs for the technology types considered in the analysis are shown in Table 1. The analysis initially included solar generation options, however these were ultimately excluded from the analysis as the cost associated with these options precludes them from being part of the efficient least cost generation mix required to meet demand.

The capital cost assumptions have been derived from two sources:

- AEMO's 2011 National Transmission Network Development Plan (2011 NTNDP).[4] As part of the 2011 NTNDP, AEMO engaged WorleyParsons to develop estimates of generation costs.

  For the purposes of the Frontier March 2012 Report, capital cost estimates from the 2011 NTNDP were used for all generation technologies.

4 http://www.aemo.com.au/en/Electricity/Planning/2011-National-Transmission-Network-Development-Plan-Consultation

For this updated final report, capital cost estimates from the 2011 NTNDP have been used only for small wind, biomass, small IGCC black coal and small supercritical black coal.[5]

- The IMO's report on the Maximum Reserve Capacity Price for the 2014/15 Capacity Year.[6]

  For the purposes of this updated final report, the capital cost estimate from the IMO's report have been used for OCGT plant.[7] This cost estimate is higher than the estimate of the cost of an OCGT plant from the 2011 NTNDP (which was used for the Frontier March 2012 Report). Given the importance of an appropriate relativity between the costs of OCGT plant and CCGT plant, for this updated final report, the capital cost estimate for CCGT from the 2011 NTNDP has also been increased in proportion to the increase in the capital cost estimate for OCGT plant between the Frontier March 2012 Report and this updated final report.

Table 1: Input capital costs ($/kW, $2011/12 real)

Technology	Fuel Type	2012/13	2013/14	2014/15	2015/16
Small scale wind	Wind	$3,112	$3,195	$3,269	$3,311
Biomass	Biomass	$4,473	$4,489	$4,506	$4,522
Small scale IGCC – Black coal	Black coal	$5,123	$5,128	$5,133	$5,139
Small scale supercritical PC – Black coal	Black coal	$3,471	$3,493	$3,516	$3,538
CCGT – Without CCS	Natural Gas	$1,636	$1,636	$1,636	$1,636
OCGT – Without CCS	Natural Gas	$1,138	$1,138	$1,138	$1,138

Source: AEMO, 2011 National Transmission Network Development Plan 2011 NTNDP, Scenario 3; IMO, Maximum Reserve Capacity Price for the 2014/15 Capacity Year, Final Report, February 2012

5 The cost estimates for small-scale plant have been used to reflect the fact that plant of this size are more likely to be appropriate to the SWIS.

6 IMO, *Maximum Reserve Capacity Price for the 2014/15 Capacity Year*, Final Report, February 2012.

7 The capital cost estimates from the IMO's report have been converted into real 2011/12 dollars.

Fuel costs

For the purposes of the Frontier March 2012 Report, fuel cost estimates for each generation technology were sourced from the 2011 NTNDP.

For the purposes of this updated final report, the assumed coal price and the assumed gas price have both been updated, in line with the Authority's views on market conditions for these fuels:

- The coal price has been increased to $3.25/GJ, which is the Authority's view on the net-back price of coal in Western Australia.
- The gas price has been increased to $9.28/GJ for CCGT and to $11.35/GJ for OCGT, based on the Authority's view of the likely response to an increase in the coal price to the estimated net-back price of $3.25/GJ.

Fuel cost assumptions for the purposes of this updated final report are listed in Table 2.

Table 2: Input fuel costs ($/GJ delivered, $2011/12 real)

Fuel	2012/13	2013/14	2014/15	2015/16
CCGT	$9.28	$9.28	$9.28	$9.28
OCGT (gas)	$11.35	$11.35	$11.35	$11.35
Coal	$3.25	$3.25	$3.25	$3.25
Biomass	$0.51	$0.51	$0.51	$0.51

Source: AEMO, 2011 National Transmission Network Development Plan 2011 NTNDP, Scenario 3; ERA assumptions.

Operating parameters

Input assumptions for key operating parameters for each new technology type are sourced from the 2011 NTNDP, as shown in Table 3.

Table 3: Input operating parameters

Technology	Fixed Operating and Maintenance cost ($/MW/hr, Sent out, real $2011/12)	Variable Operating and Maintenance cost ($/MWh, Sent Out, real $2011/12)	Heat Rate (Sent out)	Auxiliary losses	Carbon Rate (t/MWh, Sent Out)	Maximum capacity factor	Expected outage rate
Small scale wind	$5.04	$0.00	3.60	0%	0.00	35%	0%
Biomass	$4.80	$3.68	11.54	0%	0.02	40%	7%
Small scale IGCC – Black coal	$10.62	$13.45	8.78	18%	0.84	92%	8%
Small scale supercritical PC – Black coal	$4.39	$4.83	8.96	10%	0.85	92%	8%
CCGT – Without CCS	$1.73	$2.10	7.32	3%	0.43	93%	7%
OCGT – Without CCS	$1.09	$2.63	10.95	1%	0.64	94%	6%

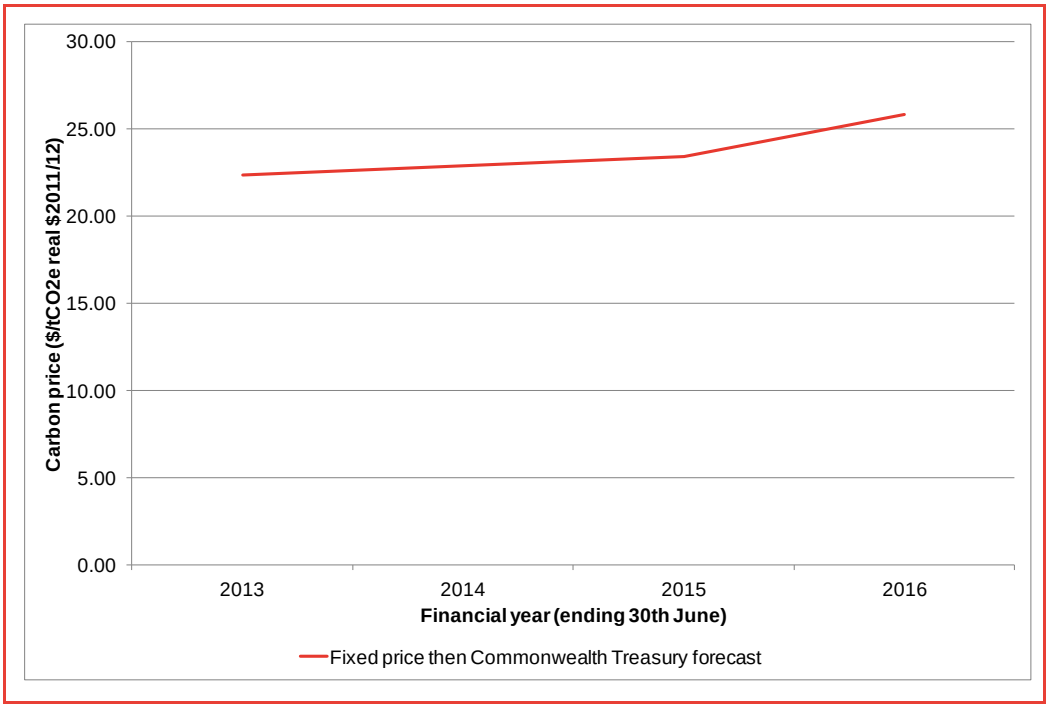
Source: 2011 NTNDP, Scenario 3

3.4 Carbon price

In modelling the stand-alone LRMC we have assumed a carbon price that reflects recent information from the Commonwealth Government on its Clean Energy Future[8] program. Currently, the Government plans to introduce a fixed price on carbon for the three years 2012/13 to 2014/15. The modelling has assumed the fixed prices as legislated. From 2015/16, the carbon price will be set by the market. Commonwealth Treasury has estimated this carbon price to be around $26/tCO2e (real $2011/12). This has been used as the assumed carbon price in our modelling, as shown in Figure 3.

We have also modelled the stand-alone LRMC on the assumption that there is no carbon price. By comparing the case with a carbon price and the case without a carbon price we are able to determine the impact of the carbon price on the stand-alone LRMC.

Figure 3: Input carbon price paths ($/tCO2e, real $2011/12)



Sources:

Commonwealth Treasury, Strong growth, low pollution*, 10/7/2011 (Chart 5.1, core policy scenario)*

Clean Energy Bill 2011 (see: http://www.comlaw.gov.au/Details/C2011B00166/Explanatory%20Memorandum/Text)

8 See: http://www.cleanenergyfuture.gov.au/

4 Stand-alone LRMC results

This section presents the results of our stand-alone LRMC modelling, which includes a carbon price.

Three sets of results are presented:

- the least cost pattern of investment in generation plant to meet Synergy's total load on a stand-alone basis
- the least cost pattern of dispatch of generation plant to meet Synergy's total load on a stand-alone basis
- the stand-alone LRMC of energy to meet Synergy's total load.

As discussed, for the purpose of this updated final report, we have not been asked to model each of the individual regulated tariff classes. For this reason, no results are presented for the individual regulated tariff classes.

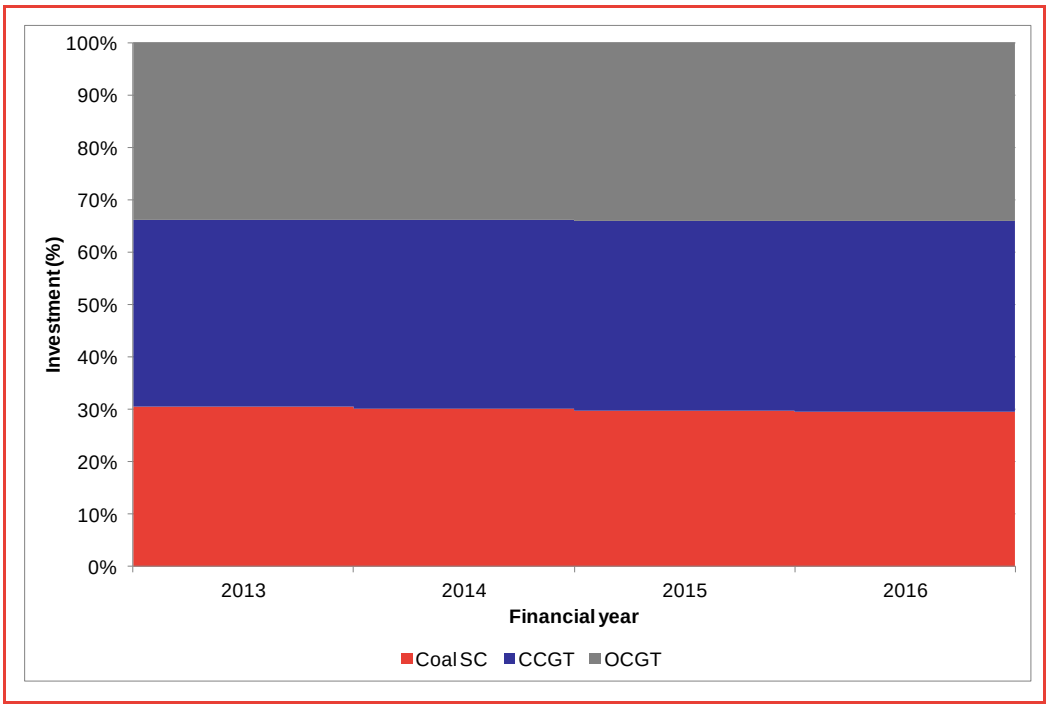
4.1 Investment

The mix of investment in generation plant to meet Synergy's total load for each year is shown in Figure 4. There is a fairly even mix of investment, with coal plant accounting for around 30 per cent of capacity, CCGT plant accounting for around 36 per cent of capacity and OCGT plant accounting for around 34 per cent of capacity.

This mix of investment in generation plant is significantly different to the mix that was reported in the Frontier March 2012 Report. In that report the generation mix to meet Synergy's total load was entirely gas plant: CCGT plant accounted for around 65 per cent of capacity and OCGT plant accounted for around 35 per cent of capacity. The change in investment mix in this updated final report is a direct result of updated input assumptions: in particular, the increase in the capital cost of OCGT plant and CCGT plant has made coal plant relatively more cost competitive and resulted in it forming part of the efficient mix of investment.

The slight decrease in the proportion of coal plant in the efficient mix over the period from 2012/13 to 2015/16 is due to the changes in the relative capital cost of coal plant and CCGT plant. The input assumptions we have adopted have a slight increase in the capital cost of coal plant over time, while the capital cost of CCGT plant remains steady in real terms. As a result, investment in CCGT plant increases over time, in favour of investment in coal plant.

Figure 4: Investment share by technology

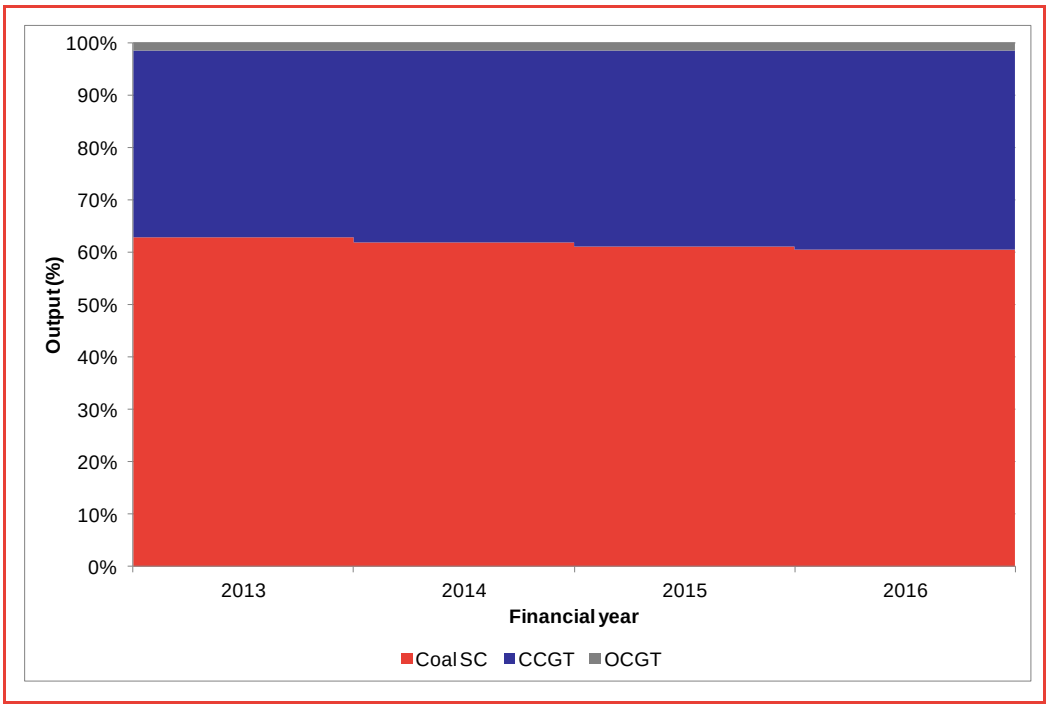


Source: Frontier Economics

4.2 Output

The mix of generation output to meet Synergy's total load for each year is shown in Figure 5. The mix of generation output follows from the mix of generation investment: coal plant accounts for around 62 per cent of output, CCGT plant accounts for around 37 per cent of output and OCGT plant runs on infrequently. As expected, coal plant operates at a higher capacity factor than CCGT plant, and CCGT plant operates at a higher capacity factor than OCGT plant. This reflects the relative economics of these plant, with coal plant having the lowest short run marginal cost and OCGT plant having the highest short run marginal cost.

Figure 5: Output share by technology



Source: Frontier Economics

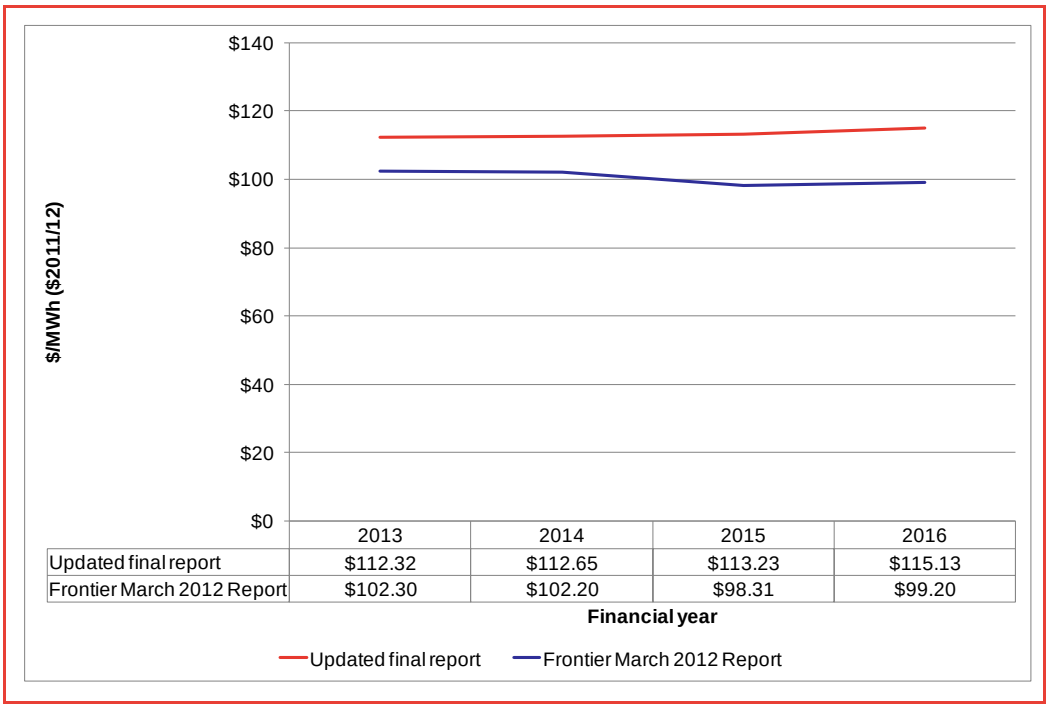
4.3 Stand-alone LRMC

The stand-alone LRMC of energy to meet Synergy's total load shape is shown for each year in Figure 6. The stand-alone LRMC results are initially around $112/MWh, but increase over the period to 2015/16 as a result of the assumed increase in the capital cost of coal plant and the assumed increase in the carbon price.

The stand-alone LRMC from this updated final report is significantly different to the stand-alone LRMC from the Frontier March 2012 Report, as shown in Figure 6. These differences are a direct result of the updated input assumptions used for this final report: the higher assumed capital cost for OCGT and CCGT plant, and the higher assumed fuel costs, have the effect of increasing the stand-alone LRMC; the lower WACC has the effect of decreasing the stand-alone LRMC. The increases in capital and fuel costs have a greater impact, with the stand-alone LRMC increasing by around $10/MWh to $15/MWh relative to the Frontier March 2012 Report.

A breakdown of these stand-alone LRMC results into the fixed and variable components of LRMC, and into peak, shoulder and off-peak costs, is provided in Appendix A.

Figure 6: Stand-alone LRMC of Synergy's total load ($2011/12)



	2013	2014	2015	2016
Updated final report	$112.32	$112.65	$113.23	$115.13
Frontier March 2012 Report	$102.30	$102.20	$98.31	$99.20

Source: Frontier Economics

5 Impact of carbon

This section presents the results of our stand-alone LRMC modelling without a carbon price. Comparing these results with the results of our stand-alone LRMC modelling with a carbon price provides an indication of the impact that the carbon price has on the stand-alone LRMC.

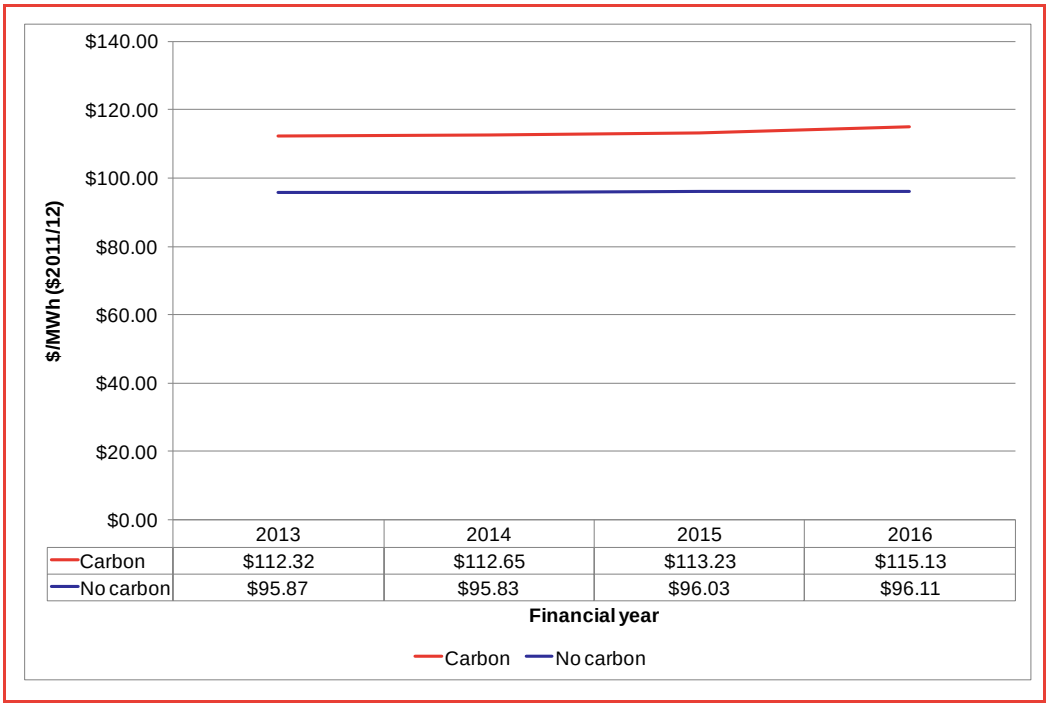
5.1 Stand-alone LRMC

The stand-alone LRMC of energy to meet Synergy's total load shape is shown for each year in Figure 6 for both the with carbon and without carbon cases.

As discussed, in the with carbon case, the stand-alone LRMC results are initially around $112/MWh, but increase over the period to 2015/16 as a result of the assumed increase in the capital cost of coal plant and the assumed increase in the carbon price.

In comparison, in the without carbon case, the stand-alone LRMC results are around $96/MWh, and remain at that level over the period to 2015/16. There is a slight increase in the stand-alone LRMC as a result of the increase in the capital cost of coal plant. But, in the absence of an increasing carbon price, the overall increase in the stand-alone LRMC over the period to 2015/16 is slight.

Figure 7: Stand-alone LRMC of Synergy's total load – with carbon and without carbon ($2011/12)



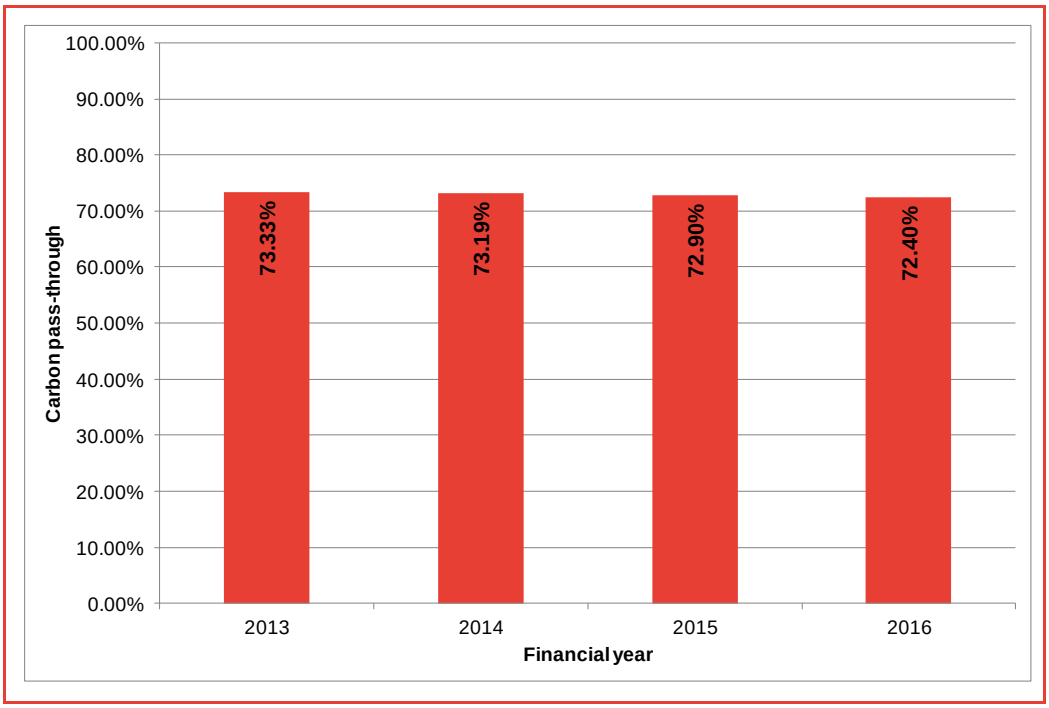
Source: Frontier Economics

5.2 Carbon pass through

By comparing the stand-alone LRMC from the with carbon and without carbon cases we are able to determine the rate at which the carbon price is passed through to the stand-alone LRMC of serving Synergy's total load.

The carbon pass-through results for the stand-alone LRMC of serving Synergy's total load is shown out in Figure 8.

Figure 8: Carbon pass-through – stand-alone LRMC of Synergy's total load



Source: Frontier Economics

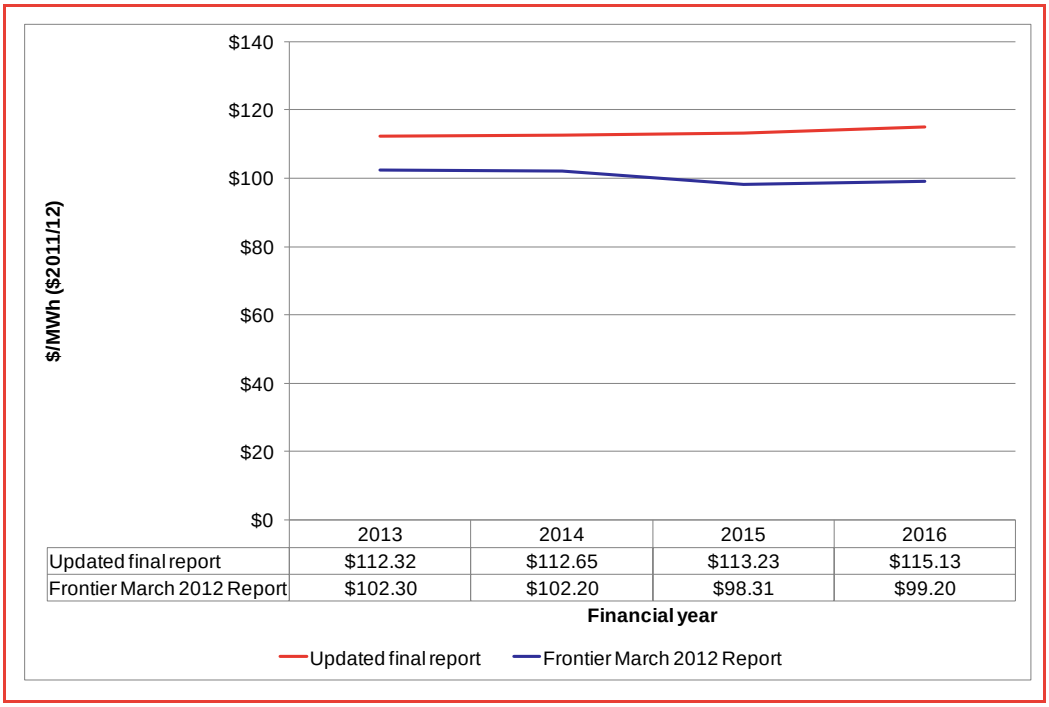
It is important to note that the carbon pass-through that is observed for the stand-alone LRMC of Synergy's total load will not necessarily reflect the carbon pass-through that would be observed for the SWIS as a whole. The principal reason for this is that the stand-alone LRMC approach effectively builds an entirely new mix of generation plant to serve load each year (and to serve Synergy's total load, which is a sub-set of total SWIS load). As a result, the mix of generation plant can immediately respond to the introduction of a carbon price. In the SWIS, however, the mix of generation plant cannot immediately respond to the introduction of a carbon price.

6 Summary of advice

Frontier Economics has been engaged by the Authority to provide advice on the efficient cost-reflective level for each tariff under the By-Laws over the period 2012/13 to 2015/16. Specifically, we have been engaged by the Authority to estimate the long run marginal cost (LRMC) of supplying energy to meet the load shape of regulated customers in each tariff class.

For the purposes of this updated final report, we have been asked by the Authority to determine the stand-alone LRMC of energy to meet Synergy's total load using a set of input assumptions that have been revised since the release of the Frontier March 2012 Report. The results of this updated modelling are shown in Figure 9.

Figure 9: Stand-alone LRMC of Synergy's total load ($2011/12)



	2013	2014	2015	2016
Updated final report	$112.32	$112.65	$113.23	$115.13
Frontier March 2012 Report	$102.30	$102.20	$98.31	$99.20

Source: Frontier Economics

Appendix A – Stand-alone LRMC results

Table 4: Fixed and variable component of stand-alone LRMC of Synergy's total load – with carbon ($2011/12)

Financial Year	Fixed component	Variable component	Total stand-alone LRMC
2013	$48.39	$63.93	**$112.32**
2014	$48.12	$64.53	**$112.65**
2015	$48.08	$65.15	**$113.23**
2016	$47.98	$67.14	**$115.13**

Source: Frontier Economics

Table 5: Fixed and variable component of stand-alone LRMC of Synergy's total load – without carbon ($2011/12)

Financial Year	Fixed component	Variable component	Total stand-alone LRMC
2013	$53.34	$42.53	**$95.87**
2014	$53.49	$42.33	**$95.83**
2015	$53.35	$42.69	**$96.03**
2016	$53.53	$42.57	**$96.11**

Source: Frontier Economics

Table 6: Stand-alone LRMC of Synergy's total load by time of use – with carbon ($2011/12)

Financial Year	Peak	Shoulder	Off-peak
2013	$116.11	$112.20	$104.86
2014	$116.35	$112.59	$105.41
2015	$116.87	$113.18	$106.09
2016	$118.59	$115.08	$108.37

Source: Frontier Economics

Table 7: Stand-alone LRMC of Synergy's total load by time of use – without carbon ($2011/12)

Financial Year	Peak	Shoulder	Off-peak
2013	$100.43	$94.44	$87.84
2014	$100.31	$94.46	$88.00
2015	$100.59	$94.80	$87.98
2016	$100.61	$94.91	$88.17

Source: Frontier Economics

Summary of advice

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